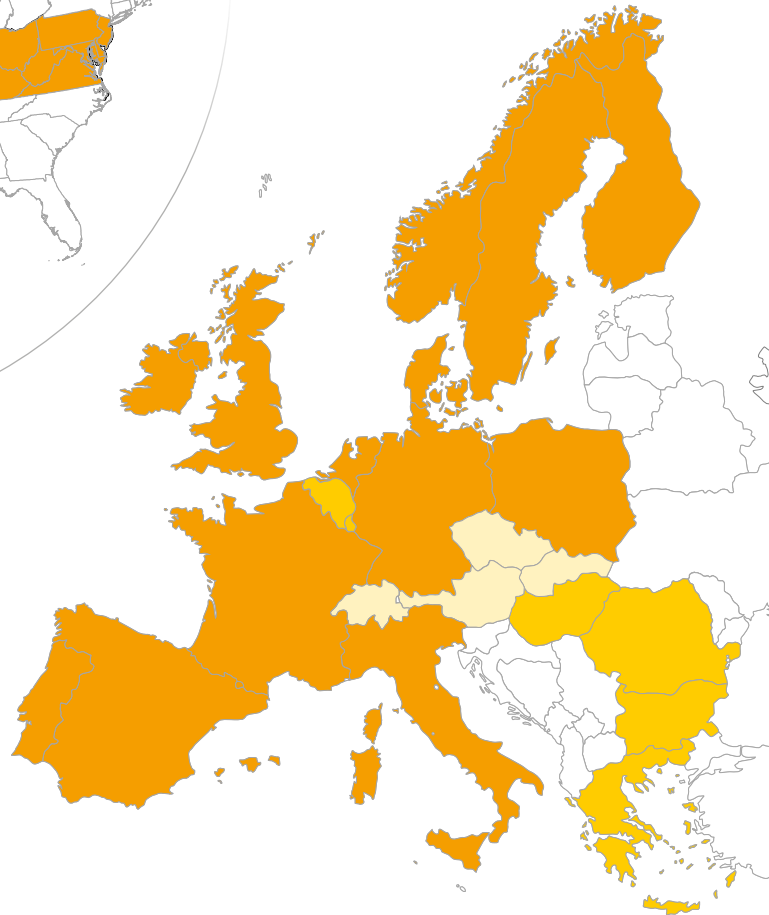
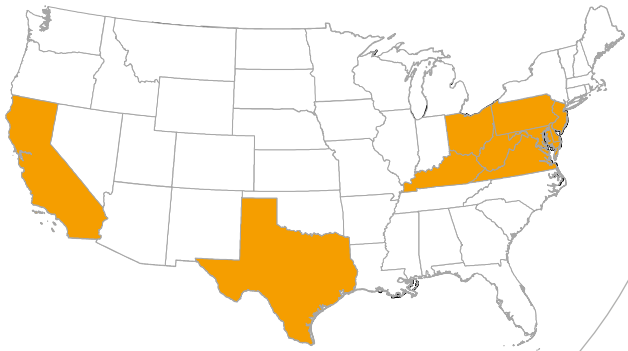


GB Wholesale Market Summary December 2021

Published January 2022



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Executive Summary

- The average power price in December was £225.6/MWh, a 23% increase from November
- The month-on-month increase in power prices was mainly driven by the increase in commodity prices which rose by between 24-42% and an increase in production from thermal generation to meet a 6% rise in transmission demand
- The rise in thermal generation primarily came from CCGTs, with average load factors increasing from 30% in November to 33% in December
- Subsequently, domestic power sector emissions rose to 4.7 MtCO₂e, a 10% increase relative to November
- The monthly average total GB carbon price increased by 17%, with UKAs trading at an average of £74/tCO₂

	Monthly value ¹	Month-on-month change	Year-on-year change	Slide reference(s)
Power prices £/MWh	225.6	+42.1 (22.9%)	+171.6 (317.4%)	<u>5, 6</u>
Gas prices £/MWh	92.7	+24.3 (35.6%)	+77.1 (493.6%)	<u>7</u>
Carbon² prices £/tCO ₂	91.6	+13.0 (16.5%)	+45.6 (99.1%)	<u>7</u>
Transmission demand TWh	25.1	+1.3 (5.6%)	+0.2 (0.9%)	<u>10</u>
Low carbon³ generation TWh	13.4	-0.4 (2.5%)	+0.2 (1.1%)	<u>11, 12</u>
Thermal⁴ generation TWh	9.9	+1.0 (10.4%)	+0.4 (3.7%)	<u>11, 12</u>
Carbon emissions MtCO ₂ e	4.7	+0.4 (10.2%)	+0.1 (2.4%)	<u>14</u>
Grid carbon intensity gCO ₂ e/kWh	211.5	+10.8 (5.4%)	+1.2 (0.6%)	<u>14</u>
Wind load factors⁵ %	42.1	-1.8 (4.1%)	+2.3 (5.5%)	<u>25</u>
Wind capture prices⁵ £/MWh	194.7	+22.7 (13.2%)	+146.3 (302.7%)	<u>27</u>

1) Values averaged over the calendar month. 2) Includes CPS and EU-ETS, the UK-ETS auctions will commence from May 2021. 3) Includes renewables and nuclear generation 4) Includes CCGTs, coal and other fossil plants. 5) Onshore wind only

Sources: Aurora Energy Research, Thomson Reuters, National Grid, Ofgem, Elexon

Agenda

- I. System performance
- II. Company performance
- III. Plant performance

Half-hourly EPEX spot price for December

EPEX spot price¹
£/MWh

Monthly average price in December 2021:
225.64 £/MWh



1) Half-hourly EPEX is the volume-weighted reference price over that half-hour interval, as provided by EPEX Spot

Historic monthly average EPEX spot price

Average EPEX spot price¹
£/MWh



— Average monthly spot price — Annual average spot price (x) Month-on-month difference (x) Year-on-year difference

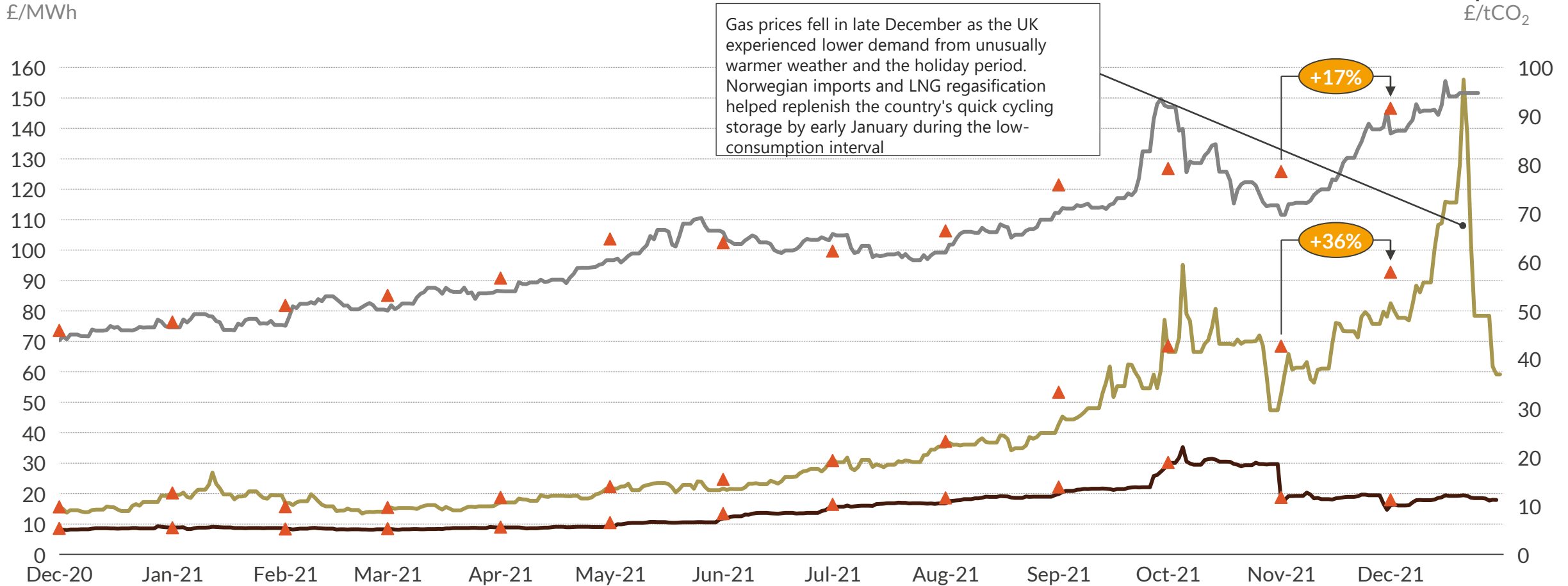
1) Average monthly EPEX is the average over the month of the volume-weighted reference prices for each half-hour interval.

Historic fuel prices

Gas, Coal and Carbon daily prices

Gas/Coal price
£/MWh

Total UK carbon price¹
£/tCO₂

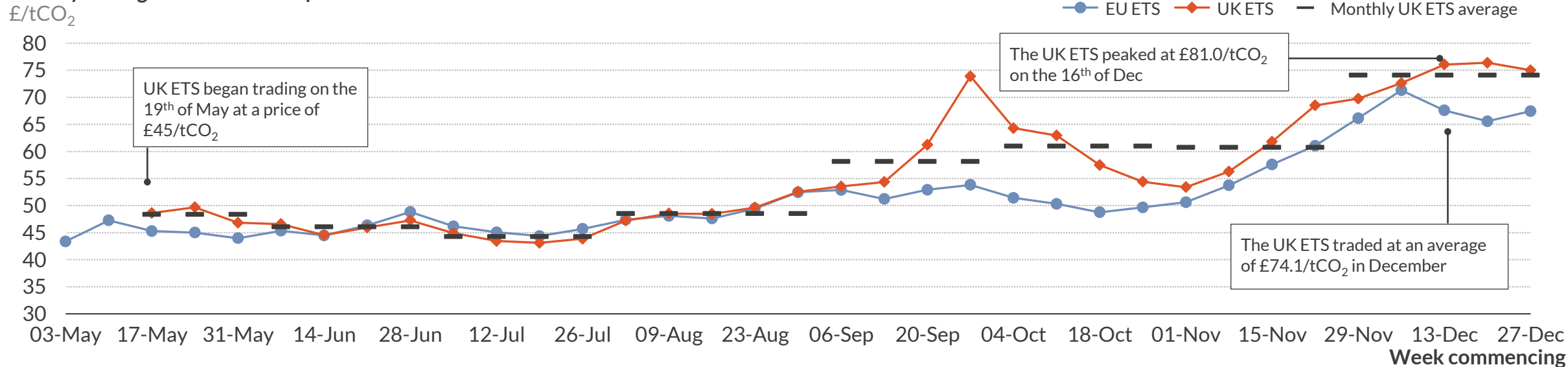


— Gas — Coal — CO2 ▲ Monthly averages ○ x Month-on-month difference

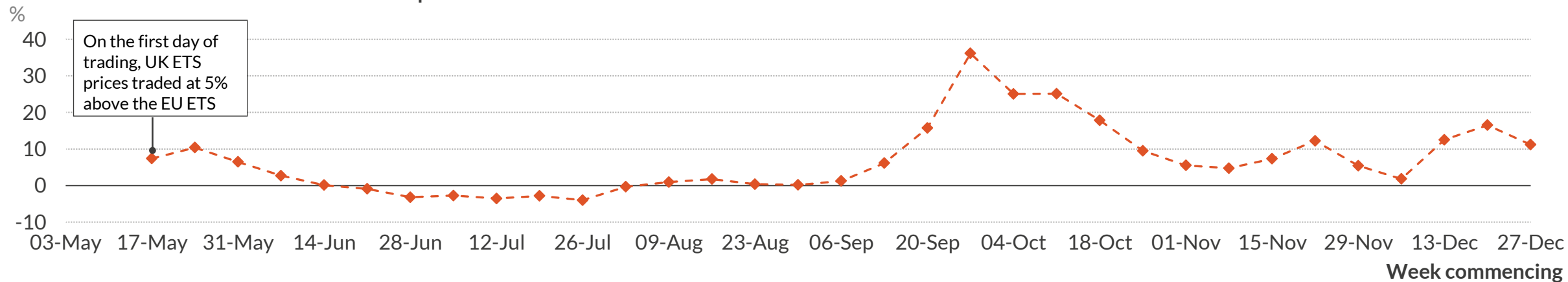
1) Includes CPS and EU ETS until 18th May 2021 and UK ETS from the 19th May 2021 onwards.

Historic UK ETS and EU ETS Prices

Weekly average EU and UK ETS prices

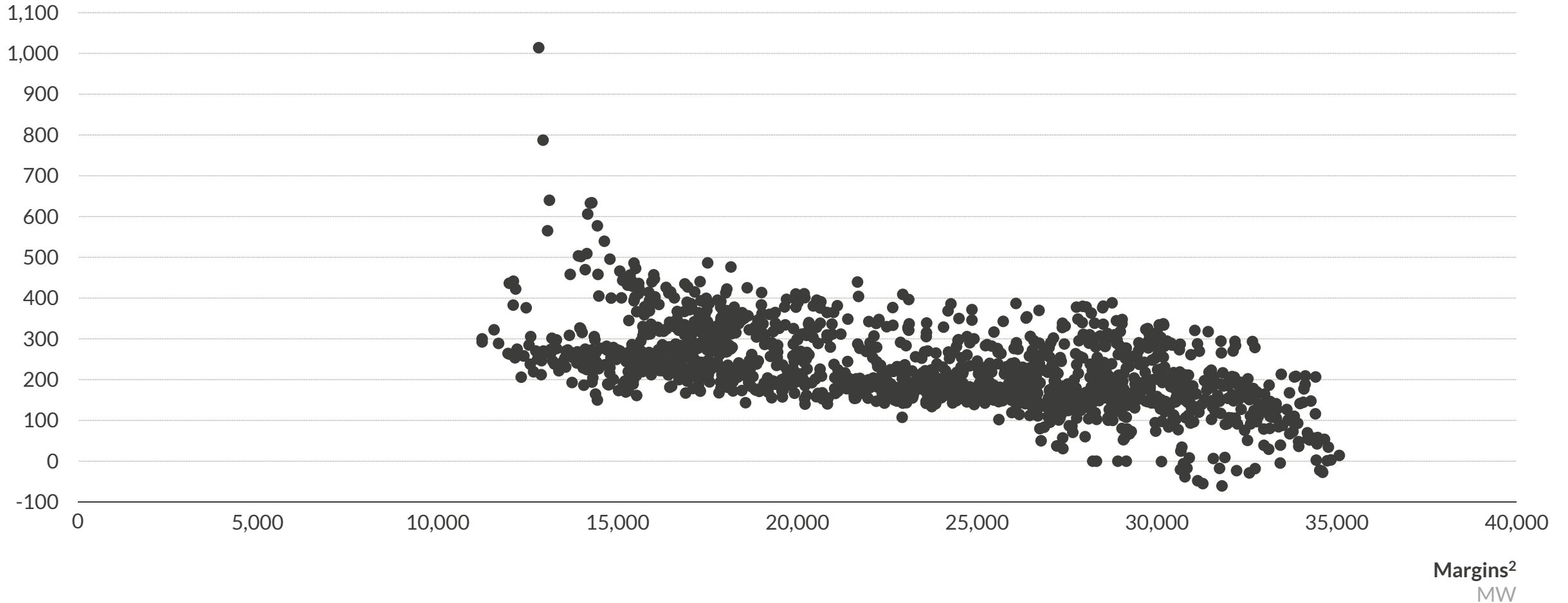


Relative difference between UK and EU ETS prices



Half-hourly spot prices against half-hourly system margins for December

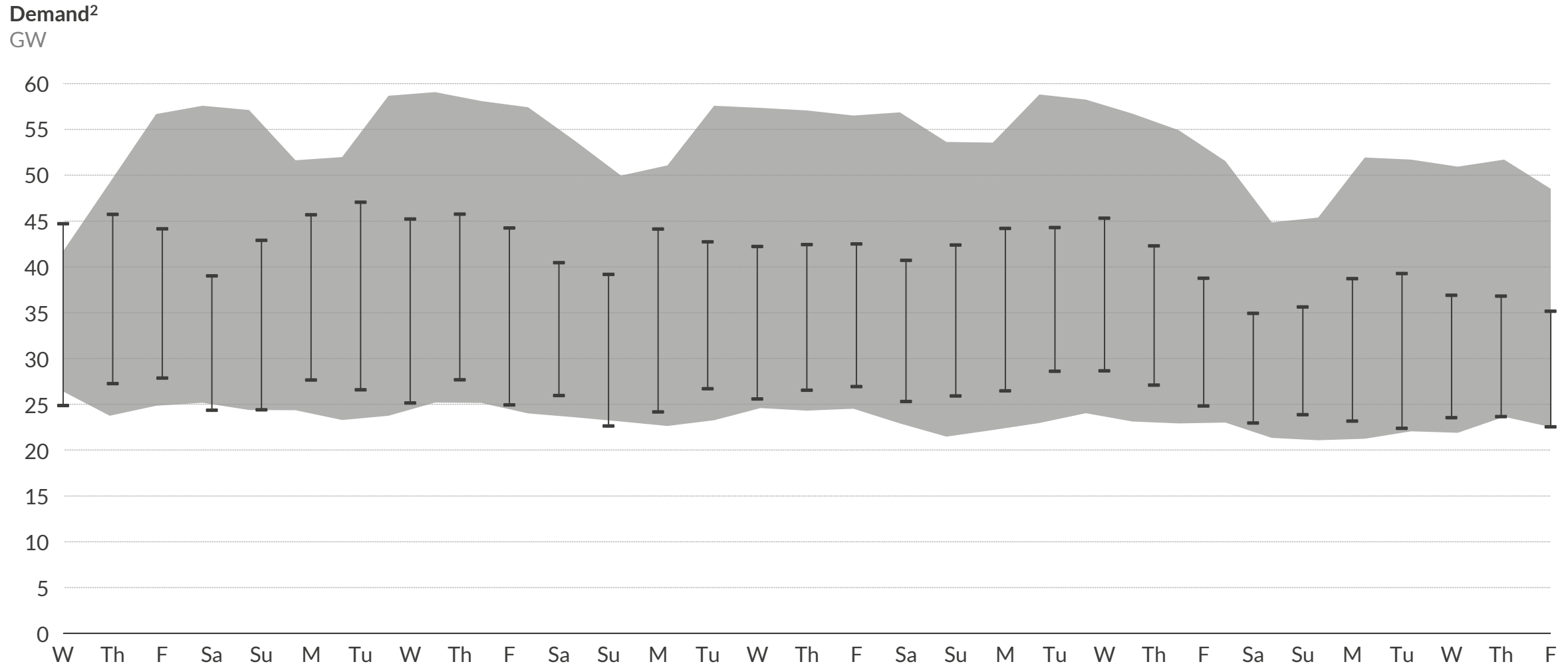
EPEX spot price¹
£/MWh



1) Half-hourly EPEX is the volume-weighted reference price over that half-hour interval, as provided by EPEX Spot. 2) Margins are calculated as the difference between MEL and Demand for each half-hour period. Demand data presented here is Initial Transmission System Demand Out-Turn, and does not include embedded demand. MEL is calculated as the sum of all transmission BM units reporting MEL values in each half-hour. Where a BMU gives multiple values in a half-hour, only the least is taken. Sources: Elexon, National Grid, Thomson Reuters, Aurora Energy Research

Daily December max and min demand

Relative to historic December max and min demand since 2010¹

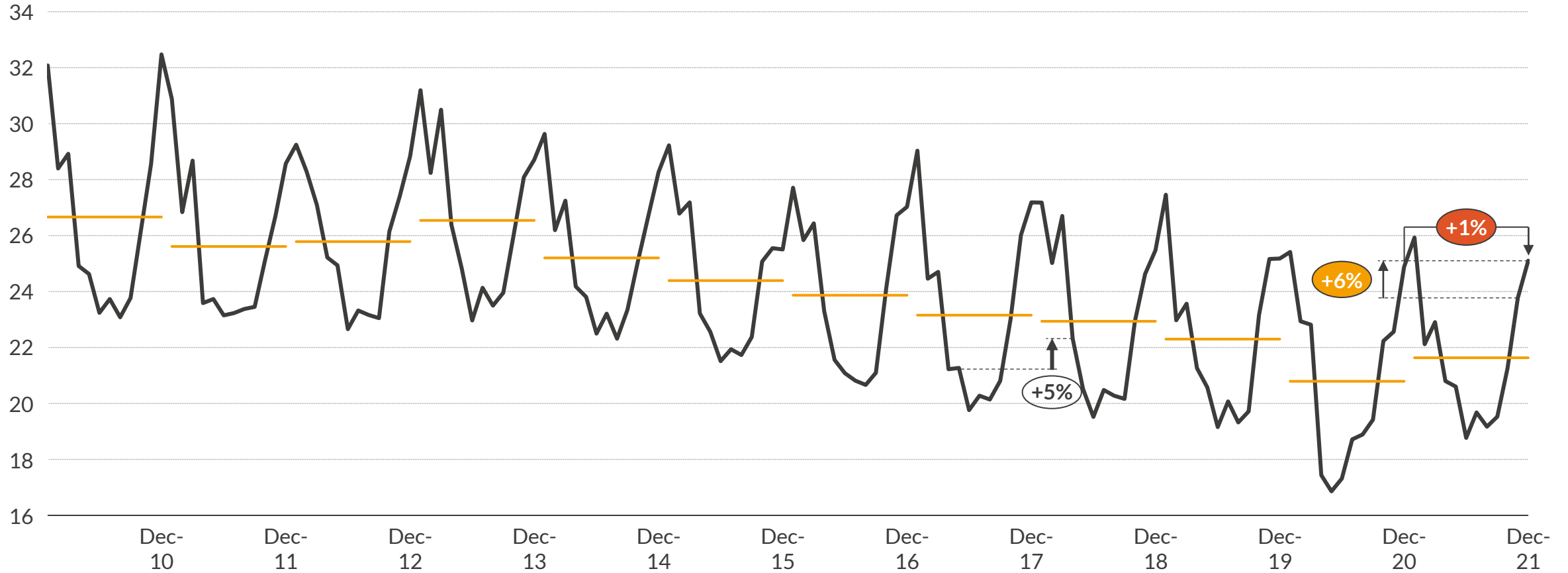


I Daily range ■ Historic maximum/minimum

1) Data from previous years is matched to the nearest weekday within the current month, to maintain the weekly demand pattern. 2) Demand data presented here is Initial Transmission System Demand Out-Turn, and does not include embedded demand.

Monthly historical demand on the transmission system

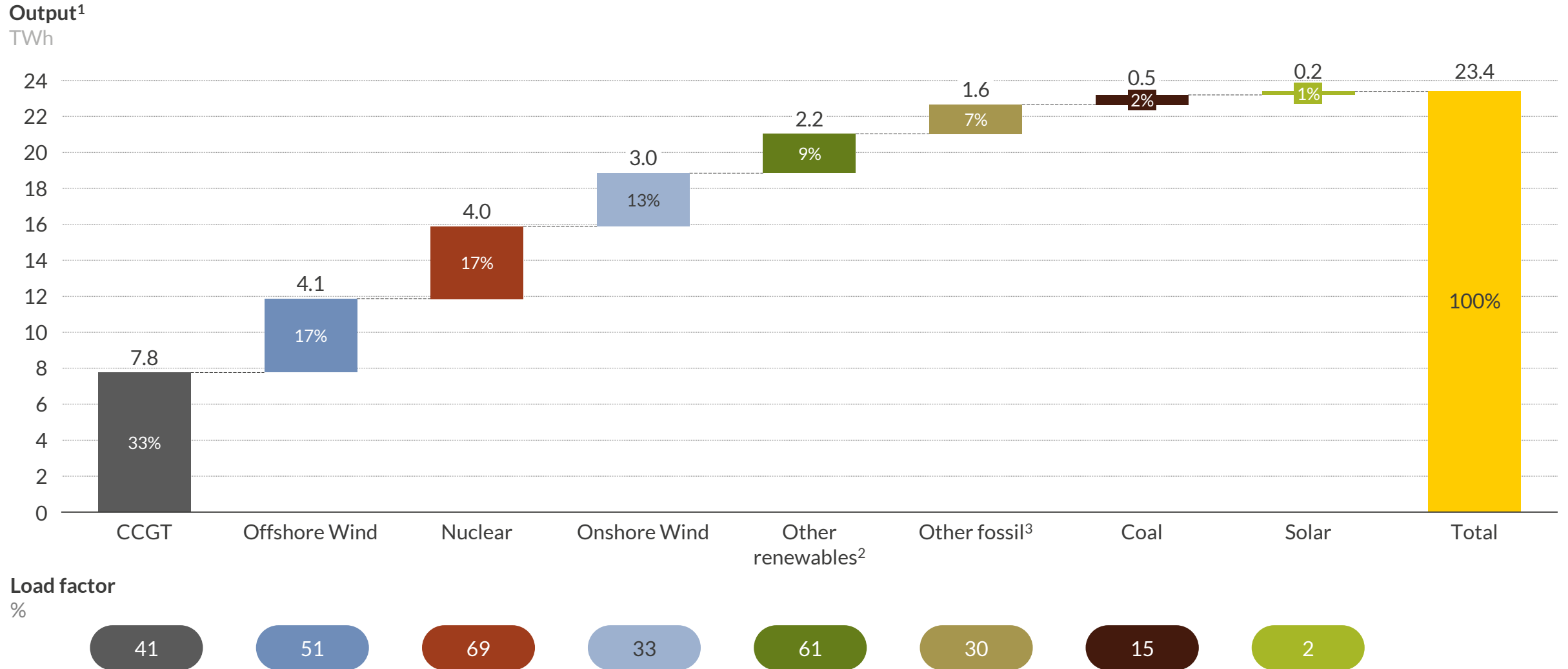
Total demand¹
TWh



— Total monthly demand — Annual average demand (x) Month-on-month difference (x) Year-on-year difference

1) Demand data presented here is Initial Transmission System Demand Out-Turn, and includes station transformer load, pumped storage demand and interconnector demand, but does not include embedded demand.

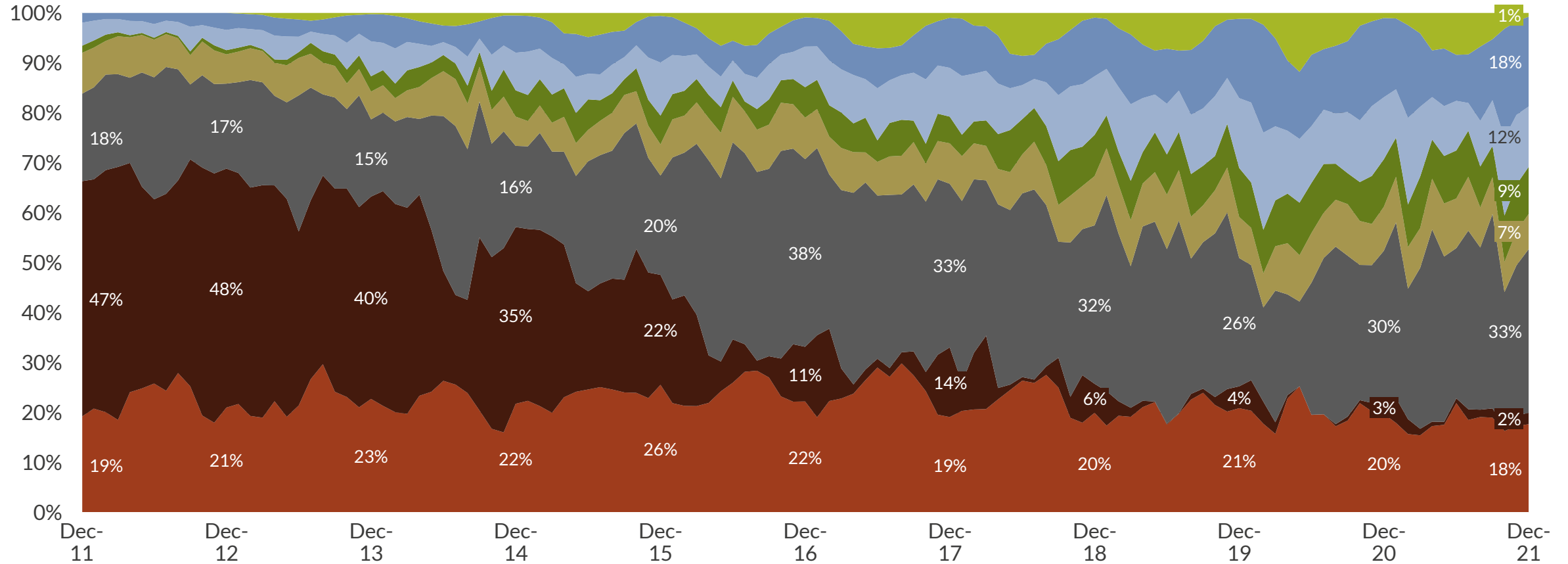
Monthly fuel mix breakdown



1) Includes outputs from generators registered as BM Units as well as embedded wind and solar PV assets. All numbers are rounded to 0.1 TWh which means that subtotals may not sum to total value. 2) Other fossil includes oil, CHP-CCGT and OCGT. 3) Other renewables includes biomass and hydro.

Historical fuel mix breakdown

Output¹
% of total

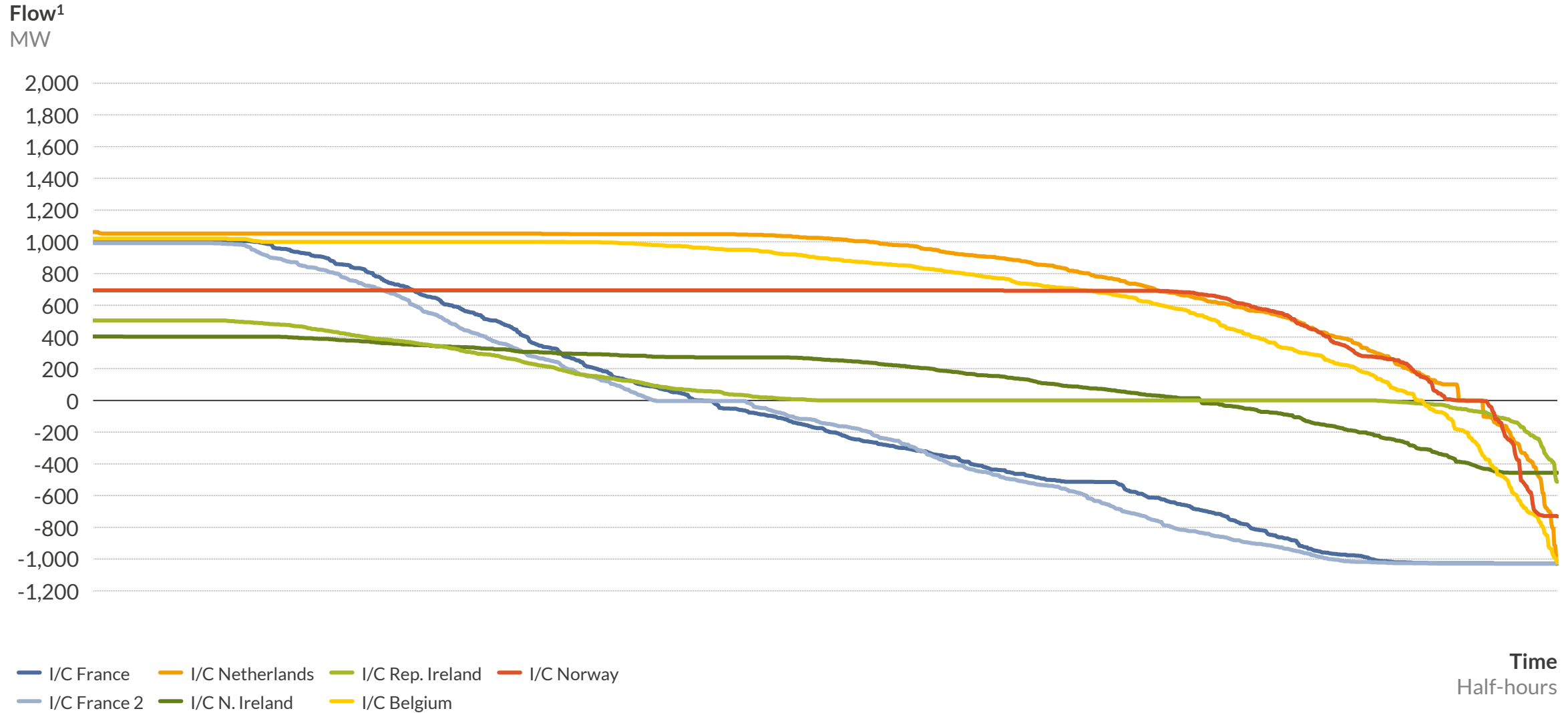


■ Nuclear
 ■ Coal
 ■ CCGT
 ■ Other fossil²
■ Other renewables³
■ Onshore Wind
 ■ Offshore Wind
 ■ Solar
 ■ Imports

1) Includes outputs from generators registered as BM Units as well as embedded wind and solar PV. 2) Other fossil includes oil, CHP-CCGT and OCGT. 3) Other renewables includes biomass and hydro.

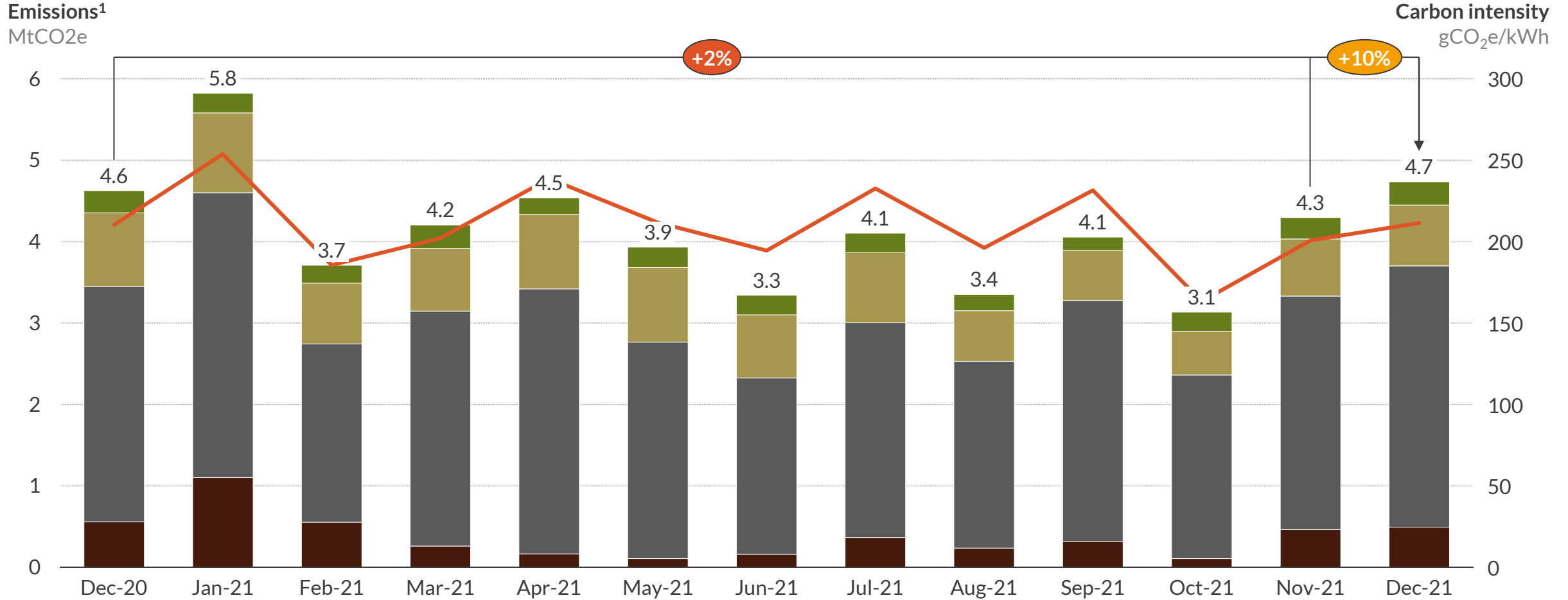
Monthly interconnector flow duration curve

Flow in each half-hour for GB interconnectors



1) Positive flow is imports into GB, negative flow is exports.

Monthly emissions by technology



■ Biomass
 ■ Other fossil²
■ CCGT
 ■ Coal
 — System carbon intensity
 x Month-on-month difference
 x Year-on-year difference

1) Please refer to Appendix for details of methodology employed to calculate emission amounts. Includes all Balancing Mechanism plants. 2) Other fossil includes oil, OCGT and gas CHP-CCGT.

Agenda

I. System performance

II. Company performance (subscriber only)

III. Plant performance

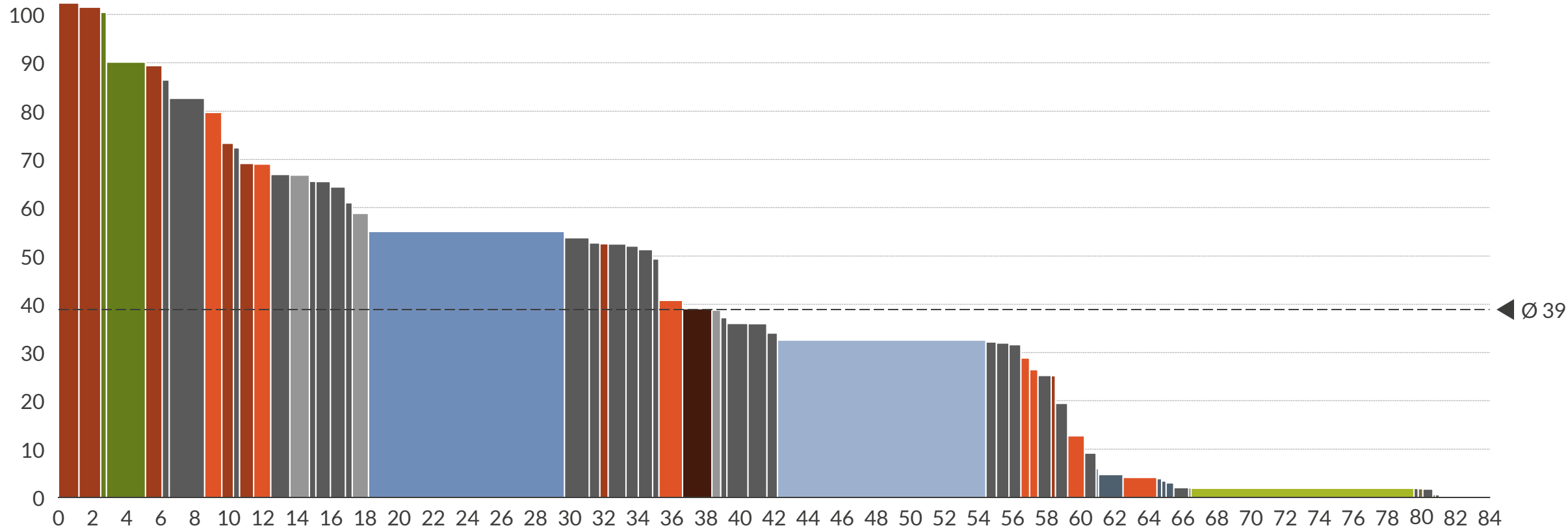
Agenda

- I. System performance
- II. Company performance
- III. Plant performance

Plant utilisation – load factors by plant

Load factor¹
%

Column width
reflects capacity



■ Biomass
 ■ Coal
 ■ Hydro
 ■ Nuclear
 ■ Offshore Wind
 ■ Onshore Wind
 ■ Solar
■ CCGT
 ■ Gas CHP-CCGT
 ■ Interconnector
 ■ OCGT
 ■ Oil
 ■ Pumped Storage

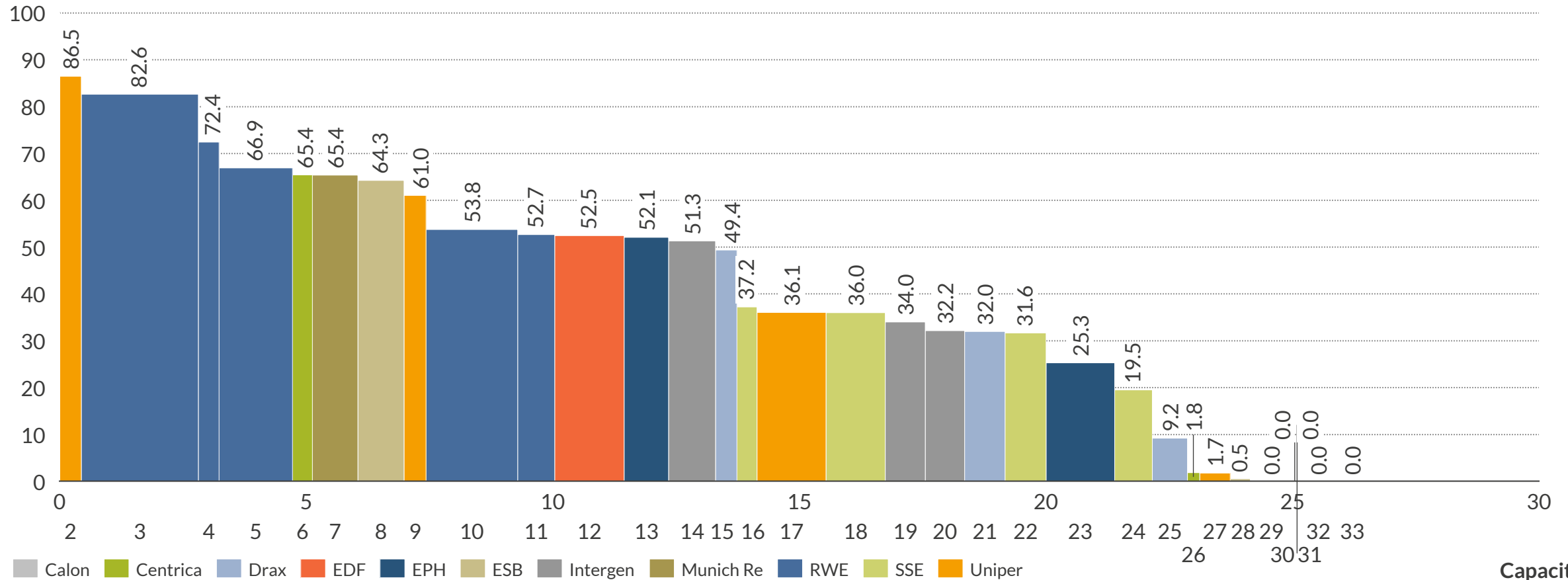
1) Represents 60 plants with highest capacity according to the Balancing Mechanism (BM) database, as well as aggregated data for wind and solar. Capacity of each plant represents the sum of capacities of all its generators that have been active at least once in the last three months. Please refer to Appendix for a detailed description of the data used and categories presented

CCGT plant utilisation – by plant

Full load hours¹

% of total for the period

Column width reflects capacity



Plant Names: 1. Medway, 2. Enfield Energy, 3. Pembroke, 4. Great Yarmouth, 5. Didcot B, 6. Kings Lynn, 7. Marchwood, 8. Carrington, 9. Cottam Dvpt Centre, 10. Staythorpe, 11. Little Barford, 12. West Burton B, 13. Langage, 14. Spalding, 15. Shoreham, 16. Seabank 2, 17. Connahs Quay, 18. Peterhead, 19. Rocksavage, 20. Coryton, 21. Damhead Creek, 22. Seabank 1, 23. South Humber Bank, 24. Keadby, 25. Rye House, 26. Peterborough, 27. Killingholme 2, 28. Corby, 29. Severn, 30. Glanford Brigg, 31. Killingholme 1, 32. Sutton Bridge, 33. Baglan Bay.

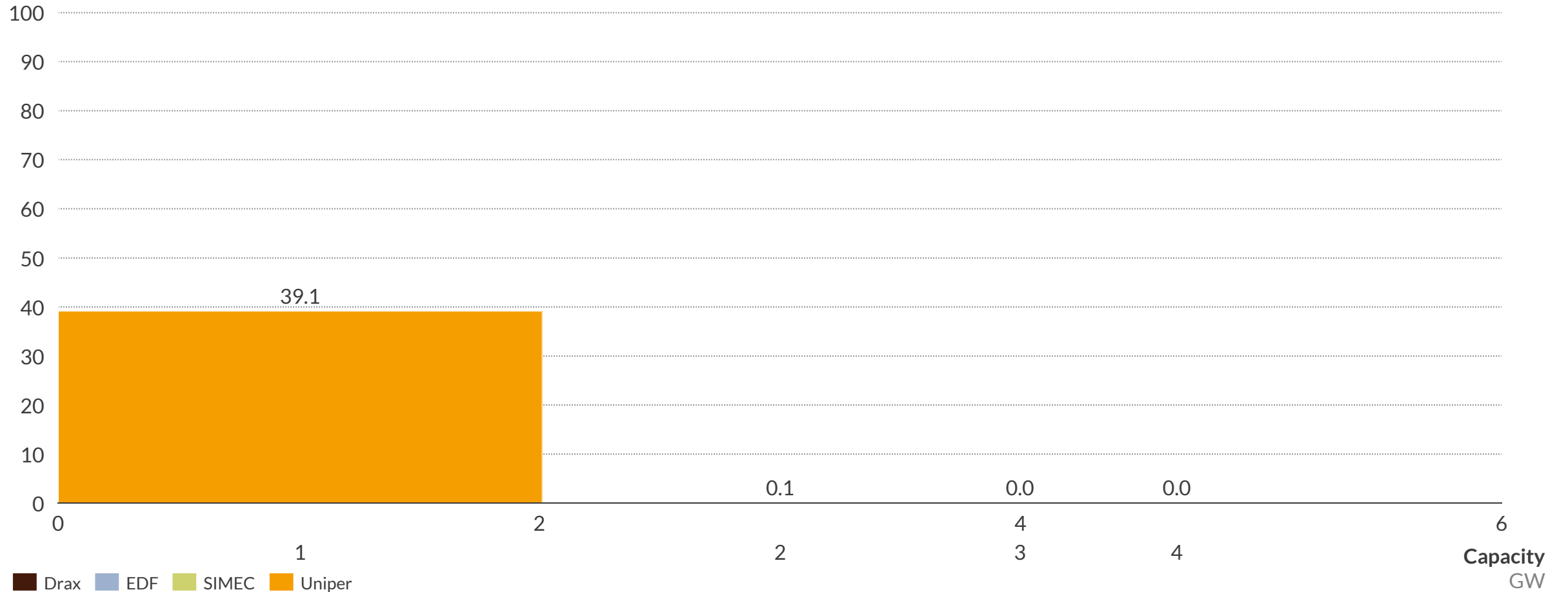
1) Includes all CCGT plants of the presented companies that report to the Balancing Mechanism

Coal plant utilisation – by plant

Full load hours¹

% of total for the period

Column width reflects capacity

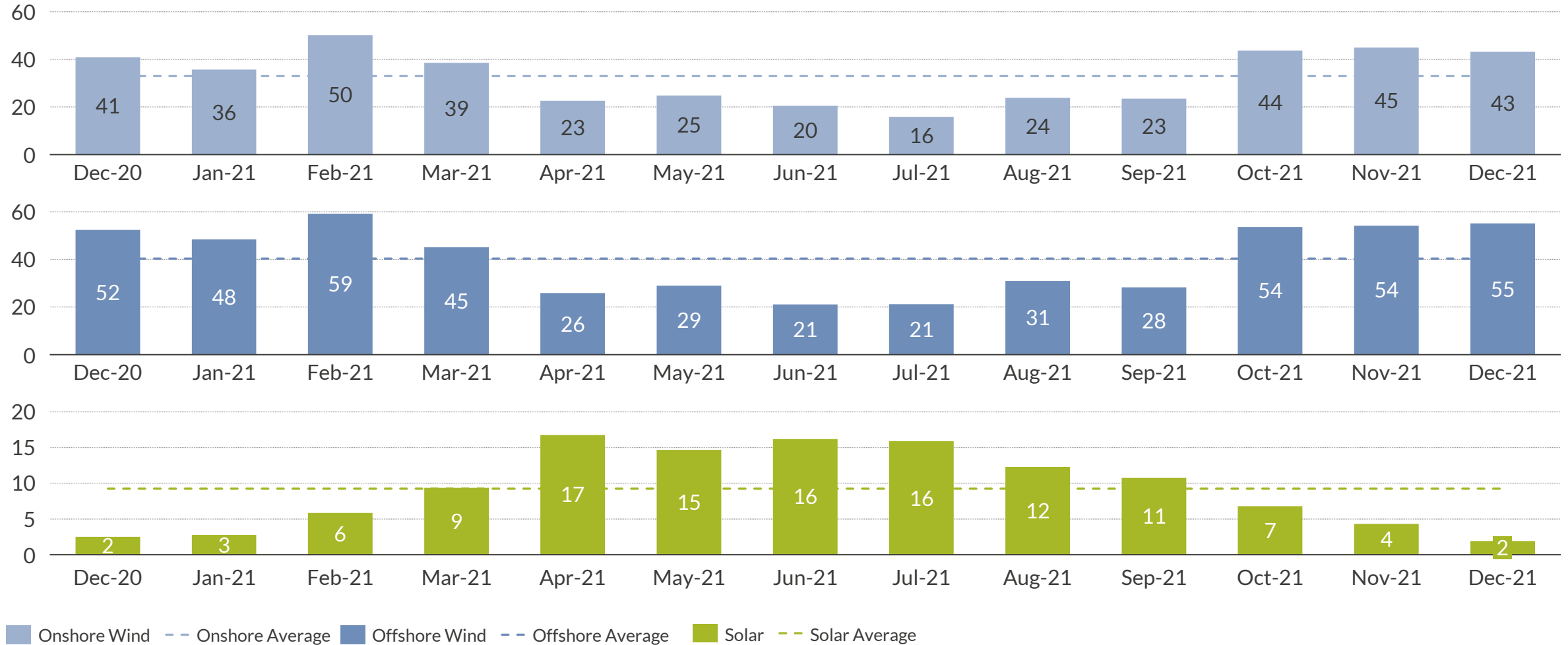


Plant Names: 1. Ratcliffe, 2. West Burton, 3. Uskmouth, 4. Drax Coal.

1) Includes all coal plants of the presented companies that report to the Balancing Mechanism

Monthly load factors by technology

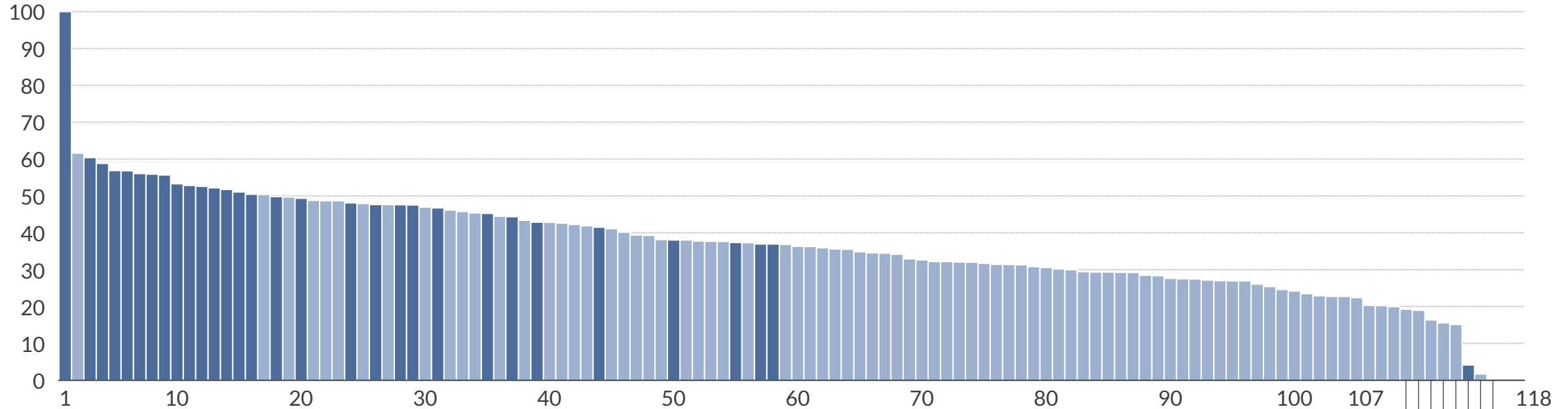
Average load factor¹
%



1) Includes outputs from generators registered as BM Units as well as embedded wind and solar PV

Wind farm utilisation – load factor by wind farm

Load factor¹
%



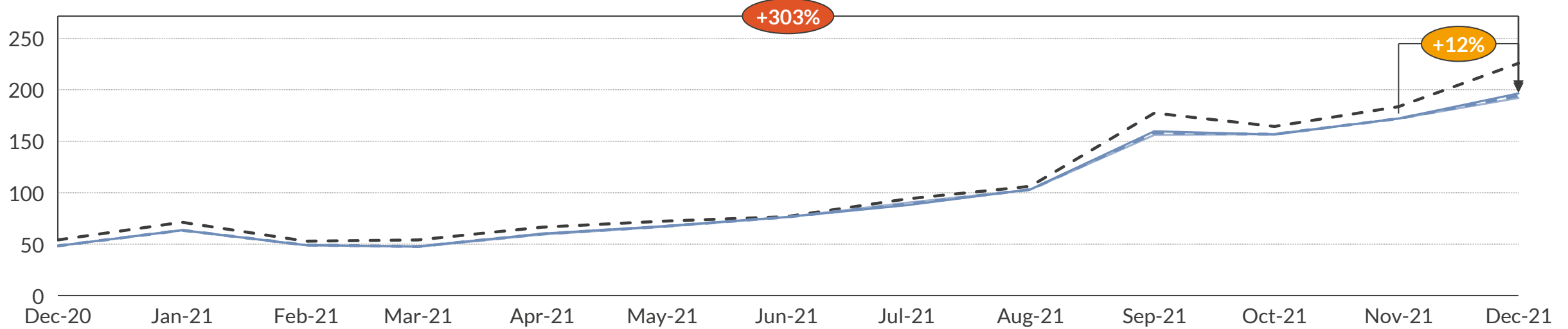
Plant Names: 1. Triton Knoll OSP West 1, 2. Whiteside Hill, 3. East Anglia One, 4. Dudgeon, 5. Hornsea 1, 6. Walney Extension, 7. Race Bank, 8. West of Duddon Sands, 9. Rampion, 10. London Array, 11. Westermost Rough, 12. Galloper, 13. Lincs, 14. Humber, 15. Walney, 16. Burbo Extension, 17. Brockloch Rig 2, 18. Beatrice, 19. Halsary Windfarm, 20. Greater Gabbard, 21. Crystal Rig, 22. Aikengall 2, 23. Cour, 24. Hywind Scotland, 25. Dunmaglass, 26. Moray East-1, 27. Sanquhar Community, 28. Sheringham Shoals, 29. Moray East, 30. Beinn an Tuirc III, 31. Gwynt y Mor, 32. Carraig Gheal, 33. Dorenell, 34. Pen y Cymoedd, 35. Gunfleet Sands, 36. Blackcraig, 37. Thanet, 38. Fallago Rig, 39. Moray East-3, 40. Stronelairg, 41. Auchrobert, 42. Andershaw, 43. Kilgallioch, 44. Barrow, 45. Corriegarth, 46. Gordonstown, 47. Camster, 48. Millennium, 49. Assel Valley, 50. Burbo Bank, 51. Afton, 52. Kilbraur, 53. Roths Extension, 54. Bad a Cheo, 55. Aberdeen, 56. Farr, 57. Robin Rigg, 58. Ormonde, 59. Freasdail, 60. Baillie, 61. Berry Burn, 62. Beinneun, 63. Gordonbush, 64. Minsca, 65. Strathy North, 66. Clyde, 67. Dersalloch, 68. A Chruach, 69. Galawhistle, 70. Gordonbush WF Extension, 71. Bhlaraidh, 72. Beinn An Tuirc, 73. Coire Na Cloiche, 74. Mid Hill, 75. An Suidhe, 76. Harburnhead, 77. Hill of Glaschyle, 78. Hare Hill Extension, 79. Clashindarroch, 80. Burn of Whilk, 81. Ewe Hill, 82. Glens of Foudland, 83. Edinbane, 84. Hill of Towie, 85. Embedded Wind, 86. Tullo Extension, 87. Braes of Doune, 88. Griffin, 89. Middle Muir, 90. Goole Fields, 91. Tullymurdoch, 92. Toddleburn, 93. Beinn Tharsuinn, 94. Dalswinton, 95. Minnygap, 96. Mark Hill, 97. Kype Muir, 98. Whitelee, 99. Hadyard Hill, 100. Dun Law Extension, 101. Crossdykes WF-2, 102. Tullo, 103. Harestanes, 104. Crossdykes WF-1, 105. Lochluichart, 106. Arecleoch, 107. Moy, 108. Corriemoillie, 109. Black Law, 110. Craig, 111. Glenchamber, 112. Glen App, 113. Clachan Flats, 114. Triton Knoll OSP East 1, 115. Airies, 116. Kincardine, 117. Keith Hill, 118. Brownieleys.

■ Offshore Wind ■ Onshore Wind

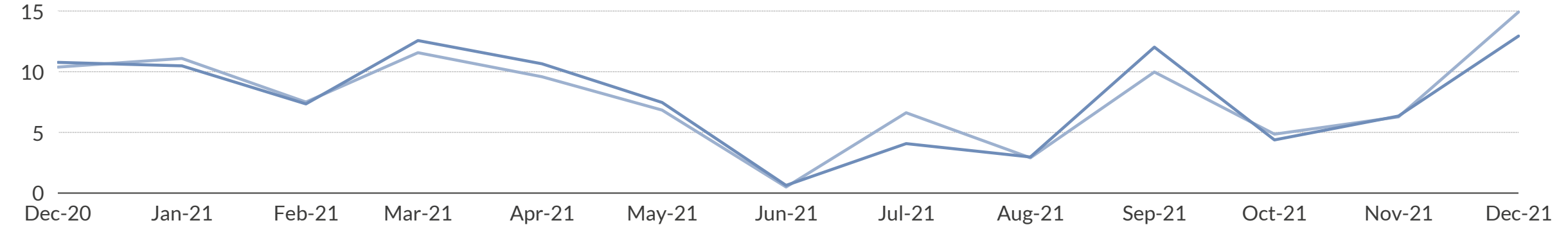
1) Represents UK wind farms reporting Balancing Mechanism Unit data. Figures presented reflect Final Physical Notification (FPN) expectations reported to the grid, which are not always representative of actual production

RES capture price versus baseload price

Baseload and capture price^{1,2}
£/MWh



Technology capture discount^{2,3} to baseload
%



-- Baseload
 — Onshore Wind
 — Offshore Wind
 — Average wind
 x Month-on-month difference (average wind)
 x Year-on-year difference (average wind)

1) Baseload price is the average monthly EPEX price; 2) Wind capture price is the load-weighted monthly average EPEX price across all wind Balancing Mechanism plants for all half-hourly periods. 3) Negative values represent capture prices above the baseload price while positive values represent capture prices below the baseload price

Data used

- Output values used in this summary reflect the sum of Final Physical Notifications (FPN) submitted by all BM Units of a given plant that have been active over the last three months.
- Capacity values used in this summary reflect the sum of capacities of individual BM Units, as reported to the Balancing Mechanism, that have been active over the last three months. They reflect long-term capacities and exclude temporary fluctuations due e.g. to plant failures or scheduled maintenance.
- Prices used in this summary are the EPEX half-hourly Reference Prices for half-hourly, two-hourly and four-hourly spot products.

Categories presented

- Full-load hours represent the plants' load factors, calculated as the ratio of the output produced in a given month to the maximum possible output given the plants' capacity.
- Running hours represent the proportion of time in a given month when a plant has been active, i.e. when at least one of its BM Units produced output greater than zero.
- Capture prices (or average output-weighted prices) are calculated as an average of EPEX half-hourly prices per MWh weighted by the plants' corresponding half-hourly outputs for all periods.
- Average gross margins are calculated as a sum of the uplift and inframarginal rent. Uplift is calculated as the difference between the EPEX price and the system marginal cost (SMC). SMC is the maximum marginal cost of all the plants with at least one generator producing above 80% of its installed capacity in a given half-hour.
- Emissions are calculated as plant output divided by electrical efficiency, multiplied by theoretical carbon content of the fuel input. The carbon content of fuel inputs is sourced from BEIS's Greenhouse gas reporting – Conversion factors 2016. System carbon intensity is calculated as the total emission divided by total electricity generated.

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